CHAPTER 6

AVOIDED CAPACITY COSTS

CHERIE CHAN

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I. INTRODUCTION AND SUMMARY

In Chapter 7 of SDG&E's testimony, entitled Capacity and Energy Value of AMI-Enabled Demand Response, SDG&E proposes to evaluate its demand-response benefits utilizing a levelized \$85/kW-year[1] avoided capacity value. DRA has evaluated SDG&E's avoided capacity proposal, and recommends using an avoided capacity cost of \$52/kW-year instead, the same value adopted by the Commission recently in its decision approving PG&E's AMI business case.[2] This \$33/kW-year difference has a significant affect on DRA's ultimate conclusion that SDG&E has overvalued its AMI project demand response benefits to the extent that the overall project is not cost-effective. This chapter will demonstrate why DRA's Avoided Capacity value of \$52/kW-year is a more appropriate measure of the AMI-enabled deferred capacity value.

The table below summarizes the differing avoided capacity cost per kW-year of SDG&E in its March 2006 filing, in its July 2006 filing, and DRA's recommendations. The rest of this chapter discusses the differences between DRA's analysis and that of SDG&E regarding each factor used to determine the overall avoided capacity value. DRA has considered five factors that it has

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[1] Testimony of SDG&E, Chapter 7, Capacity and Energy Value of AMI-Enabled Demand Response, JCM-1, line 22. March 28, 2006.
[2] CPUC D.06-07-027, Final Opinion Authorizing Pacific Gas and Electric Company to Deploy and Advanced Metering Infrastructure, July 20, 2006, p. 49.

concluded reduce the applicable CT avoided cost benefit on a net basis. They are: A) The Gas CT Market energy benefit; B) Resource availability, C) Resource adequacy planning reserves; D) Rate design flexibility; and E) Additional reliability value. Note that even by their own calculations, SG&E fails to meet its own recommended capacity value in its July 14th, 2006 update due to a "mislabeled" in its original March testimony.[3]

Table 6-1
Summary of SDG&E and DRA capacity Recommendations
[$ per kW-year]

	SDG&E (3/28)	SDG&E (7/14)	DRA
CT Avoided Cost	85	85	85
A) CT Market Energy Benefit	-22.89	-22.89	-35.37
Net CT Avoided Cost	62.11	62.11	49.63
B) Resource Availability	0	0	-14.89
C) < Planning Reserves	19.68	1.51	0
D) Rate Design Flexibility	13.79	13.79	7.5
E) Additional reliability value	0	.021 to .53	.021 to .53
Calculated Sum	95.58	77.43 to 77.94	42.29 – 42.61
Recommendation	**85**	**85**	**52**

DRA recommends using the PG&E adopted number of $52/kW-year to give SDG&E's AMI proposal the benefit of a doubt, even though evidence exists, as explained below, for using an even lower value of $42.24 - 42.61/kW-year.

II. THE LEVELIZED FIXED COSTS OF A CT GENERATOR

SDG&E starts its calculations of the levelized fixed annual costs of a CT Generator at $85/kW-year based on 1) Commission's Recommendation in

[3] Data Request Response 41-1, July 31, 2006.

rulemaking R.02-06-001[4], 2) the California Energy Commission's "Comparative Cost of California Central Station Electricity Generation Technologies[5]" staff report which cites average annual fixed costs of $80/kW-year in 2003 dollars as a proxy to the value of avoided energy, and 3) SDG&E's own calculations of a "levelized fixed cost of a CT at $85.84/kW-year.[6]"

In this case, DRA does not challenge, SDG&E's use of $85/kW-year as a base-level estimate of the levelized annual fixed cost of a CT Generator. But DRA's ultimate avoided cost estimate as it applies to SDG&E's calculation of AMI demand response benefits is different. DRA reaches a different conclusion based on the different valuations of the five factors.

III. ADJUSTMENTS

A. The Gas CT Market Energy Benefit

SDG&E first subtracts from the $85/kW-year, an annual Gas CT Market energy benefit of $22.89/kW-year.[7] This is the price SDG&E estimates that the generator of peak-capacity energy will receive for the incidental energy sold per kW-year.

DRA recommends a value of $32.45 /kW-year instead. This value is based on a compromise between SDG&E's estimate of $22.89/kW-year and the

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[4] R.02-06-001, Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure, Appendix B – Derivation of Capacity and energy values and on and off peak periods, ALJ and ACR filing , July 21st, 2004, .

[5] Comparative Cost of California Central Station Electricity Generation Technologies. California Energy Commission, Section E-3, Table D-9, August 2003.

[6] JCM-8-9, lines 28 and 1. July 14, 2006, Redlined.

[7] JCM-13, line 19. March 28, 2006.

$42/kW-year calculated by PG&E[8] that is a component of the $52/kW-year avoided capacity cost that the Commission adopted in the PG&E AMI case. Though DRA is willing to compromise on this matter to give SDG&E's AMI proposal the benefit of a doubt, the $42/kW-year estimate is closer to what one would get if one considered the fact that net energy value benefits are worth more during critical peak times, as explained below. Indeed, SDG&E acknowledges that there is considerable variation in estimates of the net energy value benefits, and cites a range of values offered by TURN in its SCE GRC ($8.76/kW-year) and PG&E AMI proceeding ($57.33/kW-year).[9] SDG&E, however, does not explain the variation in values or why one is preferable to the other.

There is a distinct difference between a calculation of the market energy benefit of a CT, depending on whether it is used year-round, or only during critical price periods. SDG&E has calculated the CT market energy benefit by utilizing a straight average of energy prices across 21 years. DRA contends that the prices at times during which demand response events are likely to occur should be weighted more heavily in this calculation, since the energy prices will also be higher during this period of constraint. In fact, this is the very purpose of demand response.

When energy from a CT is sold during a critical peak event (up to the top 91 hours per year), it will bring in a higher price when sold than energy produced

[8] PG&E-4 Opening Testimony, page 4-4, line 2. A.05-06-028 Exhibit 4.

[9] JCM-13, lines 5-6, citing Nahigan, Shilbert, G, Marcus, W. Analysis of PG&E's Proposed Advanced Metering Infrastructure Application, TURN, January 18, 2006, Table 8, p. 87. A.05-06-028, Exhibit 201.

during the CT's normal operating hours of 822 hours per year.[10] For example, energy sold at roughly the 91st-highest most expensive hour of the year would result in a significantly higher price than the energy sold the rest of the year. The straight average projected electricity price from 2005 through 2025 according to SDG&E is $62.45/kWh. The projected energy price at the 90.64 percentile, roughly the 822nd hour of each year, is $94.70/kWh and $130.56/kWh at the $98.96[11] percentile, roughly the 91st hour of the year. DRA understands that a particular price during a particular hour is an imperfect proxy for the projected price of energy during CPP or regular periods. However, the ratios of these prices to one-another are still valid in evaluating the relative prices of energy at Critical times.

The ratio of prices at the CPP-like time to the average price is 2.09061.[12] If SDG&E were to ramp up its projected energy value with the same ratio, it would arrive at a value of $47.85, slightly above the Net Energy Benefit of $42/kW-year calculated by PG&E[13] and adopted by the Commission,[14] in the PG&E AMI case. DRA is willing to compromise between its calculated value and SDG&E's, and recommends an averaged avoided cost value of $35.37, the

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[10] Comparative Cost of California Central Station Electricity Generation Technologies. California Energy Commission, Section E-3, Table D-5, August 2003.

[11] (8784 hours per year – 822 hours that combustion turbine is run per year/)8784 hours per year = % of time combustion turbine is running, 98.96%.

[12] $130.56/kWh/$62.45/kWh – 2.09061

[13] PG&E-4 Opening Testimony, Page 4-4, line 2. A.05-06-028, exhibit 4.

[14] Final Opinion Authorizing Pacific Gas and Electric Company to Deploy Advanced Metering Infrastructure, Decision 06-07-027, July 20, 2006, Page 49.

mean of SDG&E and DRA's recommendations. DRA supports use of this higher net energy benefit because it would give more weight to the fact that the value of energy is higher during critical peak periods.

B. Resource Availability

DRA raises the point that the capacity value of demand-response programs is actually lower than that of a combustion turbine, because its availability is limited. While a CT can be fired at almost any-time, demand response events are usually called on a day-ahead basis and must be called during the summer on-peak period. Furthermore, demand response programs do not result in reliable, predictable usage reductions. For this reason, DRA recommends a reduction of 30% from the net of the CT Avoided Cost – the CT Market Energy Benefit. The 30% recommendation follows calculations by Southern California Edison which show that it will exceed its capacity during non-peak, non-summer periods approximately 30% of the time, as shown in the table below.

Whereas a Combustion Turbine is available every hour of the year and operates approximately 822 hours per year,[15] only thirteen seven-hour demand response events can be initiated per year under SDG&E's PTR and CPP proposals, for a total of 91 hours. Even if SDG&E's critical-peak events were utilized the maximum 91 hours per year,[16] this will not replace the need for a CT generator

[15] Comparative Cost of California Central Station Electricity Generation Technologies. California Energy Commission, Section E-3, Table D-5, August 2003.
[16] (13 events, 7 hours each = 91 hours of CPP)

because the CT generator will be needed for the other 731 hours, or 89%[17] of the time each year when they potentially might be dispatched, as they currently are today.

Below are the results of a model run by SCE and adopted by the Commission to calculate the Loss of Load Probability (LOLP) that the electricity system will be unable to serve some of the demand during different times of the year. A demand-response program restricted to on-peak summer hours will not capture the estimated 30% chance that demand response could be needed but un-usable on non-peak summer days.

Table 6-2

LOLP Factors at Southern California Edison

As a ratio to 1

Relative LOLP Factors (Sum = 1)				
Summer			Winter	
On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak
0.701	0.205	0.009	0.081	0.004

[18]

A valuation of demand response should also be lowered due to limitations of the program. Only thirteen event-days can be called, but more days may be needed. If SDG&E runs out of demand response CPP days, then standby generators would still be required. Nevertheless, to give SDG&E's AMI program the benefit of a doubt, DRA assigned used the value of a CT during an entire

[17] 822 – 91 = 731 hours. 731 hours/822 hours = 89%

[18] Southern California Edison, 05-05-023, SCE-2 (Updated), Phase 2 of 2006 General Rate Case, page 29. Marginal Cost And Sales Forecast Proposals, September 6, 2005. Page 26, Table I-8

summer given the potential to call more CPP days than the program allows in the event of emergencies.

As an example, in the San Francisco Bay Area, "Spare the Air" days were instituted to encourage commuters to take public transit on high-smog days. The Summer 2006 Spare the Air Season runs from June 1 through October 13. However, the Bay Area Air Quality Management District exhausted its supply of three budgeted Spare the Air days by late June: even with additional emergency funding, the last Spare the Air Day of 2006 was utilized on July 21st before the July 2006 Heat Wave had even run its course, leaving the Bay Area without this financial incentive before even half of the summer season is over.[19] Analogously, if California faces another abnormally hot summer or extended heat wave, SDG&E system operators will run out of curtailment days. While these would normally be supplied through additional generation capacity, likely from a CT, such generation may not be available, requiring additional dispatch of PTR and CPP programs.

Even if SDG&E did not run out of its allotted number of critical-peak days, there are no guarantees that SDG&E would be able to predict expected system constraints on a day-ahead basis. For these reasons, and because demand response cannot be made available as a resource year-round, DRA recommends a

[19] Michael Cabanatuan, San Francisco Chronicle: Sfgate.com, *Smog, dangerous heat bring on region's 6th Spare the Air Day*, July 21, 2006, and sparetheair.org, a website and program of the Bay Area Air Quality Management District.

conservative reduction of the Net CT avoided cost value[20] by the Loss of Load Probability (LOLP) factor of non-peak-summer periods [21] 30%, for a value of \$13.89/kW-year. DRA considers this reduction particularly generous towards SDG&E's case for the reasons discussed above.

C. Reduced Resource Adequacy Planning Reserves

In its attempt to find more demand response benefits, SDG&E claims that, through AMI, it would be able to reduce its planning reserves because a "long term benefit of reduced demand volatility is the possibility of reducing the level of planning reserves (currently 15% to 17% of system peak)."[22] In its July testimony, SDG&E claims that "AMI could reduce planning reserves by 1% (eg., from 15% to 14%).[23]" The latter reduction in planning reserves would result in net additions to the capacity value of \$1.51/kW-year.[24] DRA finds this estimate particularly unconvincing because Resource Adequacy planning reserves are designed to mitigate generation-related risks. Demand response, on the other hand, which is affected by AMI, does not reduce generation risk. Therefore, DRA does not recommend any reduction in this area.

DRA emphasizes that the Commission has established Resource Adequacy Requirement-related policies and regulations "to ensure that there is adequate, cost-effective electric **generation** capacity for California and that such capacity is

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[20] The net CT avoided cost value includes the avoided cost of a CT – the CT Market Energy Benefit.

[21] (1)- (0.701 on-peak LOLP) ≈ 30%.

[22] JCM-14, line 5, March 28, 2006. Source is D.04-10-035, pg. 9.
[23] Id., at lines 7-8., March 28, 2006.
[24] JCM 15, line 12, filed July 14, 2006.

made available to the CAISO where it is needed for reliable transmission grid operations."[25] The reserve margin requirement is not simply based on the volatility of the load curve. Rather, this contingency is based on the magnitude of the largest supply-side risk, such as an outage in the largest power plant or on the largest transmission line. Flattening the load curve will not protect California from these unplanned emergencies, and basing demand response benefits on the assumption that the Commission will some time in the future change the reserve margin is unpersuasive. If the flattening of the demand curve also results in an overall reduction in the peak demand, this would reduce the amount of peaking resources needed. But this benefit is already captured in the CT capacity cost of $85/kW-year. For this reason, DRA does not support the capacity value SDG&E attributes to a decrease in the Resource Adequacy Requirement, and recommends that no adjustment be allowed.

D. <u>Increased Rate Design Flexibility</u>

SDG&E claims that subsequent rate design improvements will undoubtedly come to light"[26] and thus calculates the value of future, potential, rate design flexibility. While DRA agrees that AMI may enable additional rate options in the future, DRA also finds SDG&E's valuation of a $13.79/kW-year capacity value benefit[27] too speculative and over-valued. Because only a small fraction of

[25] Draft Decision of ALJ Wetzell, Opinion on Local Resource Adequacy Requirements, Rulemaking 05-12-013, mailed 5/30/2006. Emphasis added by DRA.
[26] JCM-14, lines 25-27, March 28, 2006.
[27] JCM – 15, line 2. March 28, 2006

SDG&E's energy is actually purchased on the spot market, DRA recommends only an incremental valuation of $7.50/kW-year instead.

SDG&E cites a paper by the Center for the Study of Energy Markets[28], "an evaluation of RTP benefits relative to flat rate retail pricing.[29]" This paper assumes full Real-Time Pricing (RTP) as a basis of comparison to RTP, which is a rate design and pricing strategy which neither SDG&E nor DRA would propose, especially for all residential customers. But SDG&E has adjusted the estimates in the paper downward to reflect these differences in rate design.

A more serious problem, that SDG&E has not accounted for, is the generation market assumed in the paper. The author of this paper "assume[s] free entry of generators of three types. Generation exhibits no scale economies, with each generation unit having a capacity of one megawatt.[30]" However, the reality of California's generation supply does not reflect the paper's theoretical assumptions. While theoretical calculations provide good illustrative examples, the majority of SDG&E's power supply is actually served through long-term contracts and obligations. By SDG&E's own estimates, "for 2006, SDG&E expects to receive 43 percent of its customer power requirements from DWR allocations. Of the remaining requirements, SONGS is expected to account for 17 percent, long-term contracts for 19 percent (of which 7 percent is provided by

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[28] Borenstein, Severin The Long-Run Efficiency of Real-Time Electricity Pricing, Center for the Study of Energy Markets (CSEM WP 133r) February 2005
[29] JCM-15 lines 26-27. March 28, 2006.
[30] Id., page 2.

renewable contracts expiring on various dates through 2025), Palomar for 12 percent, and spot market purchases for 9 percent. The long-term contracts expire on various dates through 2032.[31]" Thus, the bulk of SDG&E's power procurement over the next 20 years will be tied-up in long-term and nuclear contracts. Consequently, the effects of SDG&E's AMI implementation will not be nearly as dramatic, in the timeframe of this business case evaluation, as that envisioned by the academic researchers.

In light of the evidence presented, DRA cannot substantiate the additional capacity-value benefits of a potential increase in rate design flexibility as presented by SDG&E. Because SDG&E currently purchases only 9% of its energy on the spot-market, only that percentage of the energy mix, or $1.21/kW-year should receive SDG&E's RTP benefit. However, because DRA acknowledges that these long-term contracts will eventually be phased out, it recommends a value of $7.50/kW-year, an average of DRA's calculation of $1.21/kW-year and SDG&E's value of $13.79/kW-year.

E. Additional Reliability Value

In its July 14th Amended testimony, SDG&E adds an additional reliability value of $.021 to $.053/kW-year[32] based programs, "such as Programmable Controllable Thermostats, automated energy management systems, and other

[31] SDG&E Annual Financial Report, 2005. Page 96. This report can be found at: http://www.sempra.com/financials/2005report/financial.pdf.
[32] JCM-20, lines 10-11, July 14, 2006-redlined.

future technological innovations"[33] could potentially encourage customers to reduce consumption or demand on short notice with additional technology. DRA finds SDG&E's actual, proposed capacity value to be valid and does not contest the additional, small, potential benefit listed of $0.021/kW-year to $0.53/kW-year

IV. CONCLUSION

SDG&E does not make any showing or assert any reason why its avoided capacity costs are uniquely high compared to that of other utilities. It also has not provided any compelling reason why its benefits should be evaluated any differently from that decided in PG&E's recent AMI ruling. Furthermore, the California Energy Commission, when calculating the cost of avoided capacity,[34] did not calculate separate costs per utility.

An analysis by DRA resulted in a calculated avoided capacity value of $42.24 - 42.61/kW-year. However, without conceding the strength of its analysis in this case, DRA also accepts the recommended value previously determined by the Commission in PG&E's AMI proceeding. Given the information available, and DRA's evaluation of the avoided capacity value to be enabled by AMI, DRA finds a valuation of $52/kW-year to be an appropriate value for the avoided cost of capacity.

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[33] JCM-19, lines 18-20, July 14, 2006 –redlined.